

WELL ABANDONMENT APPARATUS

1

2

3 This invention relates to apparatus and a method for  
4 treating wells, especially but not exclusively for  
5 abandoning hydrocarbon-bearing wells.

6

7 When wells have reached the end of their useful  
8 life, they need to be abandoned. The top of the  
9 casing strings must be cut off near the wellhead,  
10 whilst ensuring that no further hydrocarbons can  
11 leak through the casing strings and into the  
12 surrounding area. The bottom of the annulus between  
13 the two innermost casings is in communication with  
14 the formation. Therefore, if this annulus is not  
15 completely sealed, hydrocarbons from the formation  
16 could leak out. Usually, wells are abandoned using  
17 explosives to sever the casings. These are harmful  
18 for fish and the environment. Furthermore,  
19 underwater explosions are difficult to control and  
20 there is a risk of damaging the well plug, causing  
21 it to leak.

22

1 According to the present invention there is provided  
2 well treatment apparatus comprising a cutting tool;  
3 a sealing device to seal a portion of a wellbore;  
4 and an anchor means to anchor the apparatus with  
5 respect to the wellbore.

6  
7 Preferably, the sealing device comprises at least  
8 one and preferably two annular cup devices typically  
9 orientated in the same direction to provide a double  
10 seal between the portion of the well beneath the  
11 sealing device and the surface of the well.

12  
13 Optionally, the sealing device comprises two annular  
14 cup devices orientated in opposite directions (e.g.  
15 with cups facing one another) to seal the portion of  
16 the apparatus in between the two oppositely-  
17 orientated devices from the rest of the bore.

18  
19 Preferably, a first fluid circulation device is  
20 positioned between the two oppositely orientated cup  
21 devices.

22  
23 Typically the cup devices can be cup-type seal  
24 assemblies, typically with axially extending  
25 conduits for e.g. control lines and fluid lines. A  
26 preferred cup device can be constructed from a  
27 packer (e.g. such as a gas line packer available  
28 from Double-E, Inc), modified so that its rubber  
29 part allows the packer to perform a sealing  
30 function, and including bulkhead connections  
31 providing axial passages through the packer.

32

1 Preferably, the apparatus adapted to attach to a  
2 drillstring and the sealing device is typically  
3 adapted to, in use, seal the annulus between the  
4 drillstring and the innermost casing of the  
5 wellbore.

6  
7 Typically, the cup device has a cup-shaped body  
8 (typically at least a portion of this is made from a  
9 deformable material, such as high density rubber).  
10 Preferably, a part of the cup device is adapted to  
11 deform outwards to seal the annulus upon the  
12 application of pressure from inside the cup-shaped  
13 body. In use, fluid flowing into the cup-shaped  
14 body typically deforms the cup-shaped body so that  
15 the external face of the cup presses against the  
16 inner face of the casing, preventing or restricting  
17 fluid from flowing past the cup device.

18  
19 Typically, a further fluid-circulating device is  
20 located between the sealing device and the cutting  
21 tool. Typically, fluid can be diverted between the  
22 circulating devices by dropping a ball/dart into the  
23 body of the apparatus.

24  
25 Optionally, at least one further seal is located  
26 beneath the cutting tool, to seal the portion of the  
27 bore around the cutting tool from that below the  
28 cutting tool. Preferably, the at least one further  
29 seal is a cup-type seal assembly.

30  
31 Preferably, the cutting tool comprises a jet cut  
32 nozzle that is able to cut through casings that line

1 the bore. Preferably, the nozzle is movable e.g.  
2 rotatable in two perpendicular planes (e.g.  
3 horizontal and vertical) so that the nozzle can cut  
4 circular apertures in the casing. Preferably the  
5 nozzle/cutting tool is also rotatable through 360° to  
6 enable the cutting tool to cut around the entire  
7 circumference of the casing.

8  
9 Optionally, the anchor means is located on the body  
10 of the cutting tool. Alternatively, the anchor  
11 means could be provided on a further sub separate  
12 from the cutting tool.

13  
14 Preferably, at least one part of the anchor means is  
15 laterally extendable. The laterally extendable part  
16 of the anchor means typically has a foot for  
17 engaging a wall of a casing.

18  
19 Preferably, the foot has a high-friction casing-  
20 contacting surface. Typically, the casing-  
21 contacting surface extends around the entire  
22 circumference of the anchor means.

23  
24 A typical anchor means can be provided by modifying  
25 a packer device having an expandable anchor portion;  
26 the modification typically includes the removal of  
27 the interior packing material to leave a hollow bore  
28 through the packer. Such packer devices typically  
29 have an exterior anchor portion, which is expanded  
30 on moving a first part of the anchor device relative  
31 to a second part.

32

1     Optionally, the cutting tool has at least two (e.g.  
2     three or more) circumferentially spaced feet, to  
3     engage the interior of the casing at  
4     circumferentially spaced locations. The or each  
5     foot can be mounted on a moveable arm that can be  
6     driven by a ram or alternatively at least one of the  
7     feet can be static e.g. provided on the body of the  
8     cutting tool, or on an extension of the body.

9  
10    According to a second aspect of the invention, there  
11    is provided a method of treating a well, including  
12    the steps of:

13  
14           inserting well treatment apparatus into a cased  
15           wellbore, the apparatus including a cutting  
16           tool, a sealing device and an anchor means;

17  
18           perforating the innermost casing in two  
19           vertically spaced positions; and

20  
21           injecting cement into a portion of the annulus  
22           between the two innermost casing strings to  
23           seal the annulus;

24  
25           whereby the method includes the step of using  
26           the anchor means to anchor the apparatus to the  
27           cased wellbore.

28  
29    Typically, the method includes the step of pressure  
30    testing the innermost casing before the first  
31    perforation is made by injecting a fluid into the  
32    wellbore below the sealing means.

1 Typically, the method includes the step of pressure  
2 testing the annulus before the second perforation is  
3 made by injecting a fluid into the wellbore below  
4 the sealing means and measuring the equilibrium rate  
5 of pumping as the fluid flows through the first  
6 perforation into the annulus.

7  
8 Optionally, the method includes the step of pressure  
9 testing the annulus after the second perforation has  
10 been made by injecting a fluid into the annulus to  
11 check that there are no blockages in the part of  
12 that annulus lying between the vertically spaced  
13 perforations.

14  
15 Typically, the sealing device includes two  
16 oppositely orientated cup devices, and the cement is  
17 injected into the annulus from an aperture in the  
18 apparatus located between these two cup devices.

19  
20 Optionally, the method includes the step of pressure  
21 testing the sealed annulus by positioning the  
22 apparatus so that the sealing device lies between  
23 the two vertically spaced perforations and by  
24 injecting fluid into the wellbore below the sealing  
25 device.

26  
27 Preferably, the method includes the step of using  
28 the cutting tool to sever the casings above the  
29 perforations after the annulus has been sealed, and  
30 typically tested for seal integrity.

31

1 Typically, the method including the step of  
2 undertaking at least one pressure test by injecting  
3 fluids, whereby during the pressure test, the  
4 apparatus is anchored to the casing by the anchor  
5 means to counter the upwards force on the apparatus  
6 by the injected fluids.

7  
8 Typically, the well treatment apparatus is mounted  
9 on a drillstring and is manoeuvred in the wellbore  
10 by raising and lowering the drillstring.

11  
12 Typically the fluid used in the pressure tests is  
13 water, but in some circumstances cement or other  
14 fluids can be used.

15  
16 An embodiment of the invention will now be described  
17 by way of example only and with reference to the  
18 following drawings, in which:-

19  
20 Fig 1 shows a partial cross-section of an  
21 abandonment string inserted into a wellbore to  
22 be abandoned;

23 Fig 2 shows a partial cross-section of the  
24 abandonment string piercing the 9 5/8" casing;  
25 Fig 3 shows a partial cross-section of the  
26 abandonment string making a second, higher cut  
27 in the 9 5/8" casing;

28 Fig 4 shows a partial cross-section of the  
29 abandonment string injecting cement into the  
30 annulus between the cuts;

1           Fig 5 shows a partial cross-section of the  
2           abandonment string performing a final pressure  
3           test on the cemented annulus;  
4           Fig 6 shows a partial cross-section of the  
5           abandonment string cutting through all the  
6           casing strings at the wellhead;  
7           Fig 7 shows a schematic cross-section of the  
8           abandonment string pressure testing the 9 5/8"  
9           casing string;  
10          Fig 8 shows a schematic cross-section of the  
11          abandonment string making a cut in the 9 5/8"  
12          casing and pressure testing the annulus between  
13          the 9 5/8" casing and the 13 3/8" casing;  
14          Fig 9 shows a schematic cross-section of the  
15          abandonment string making a second cut in the 9  
16          5/8" casing;  
17          Fig 10 shows a schematic cross-section of an  
18          integrity check of the cement in the annulus  
19          between the two cuts;  
20          Fig 11 shows a schematic cross-section of  
21          cement being injected into the annulus between  
22          the two cuts;  
23          Fig 12 shows a schematic cross-section of the  
24          cement in the annulus between the cuts being  
25          pressure tested;  
26          Fig 13 shows a schematic cross-section of the  
27          casings being cut near the wellhead;  
28          Fig 14 shows a cross section of three cup-type  
29          seal assemblies mounted on two circulating  
30          subs;  
31          Fig 15 shows a side view of a cutting tool;

1           Fig 16 shows a side view of a portion of a  
2           cutting tool;  
3           Fig 17 shows a schematic diagram of an  
4           abandonment string;  
5           Fig 18 shows a perspective view of the  
6           abandonment string of Fig 17;  
7           Fig 19 shows a perspective view of a cup-type  
8           assembly;  
9           Fig 20 shows an end view of a body member of  
10          the cup-type assembly of Fig 19;  
11          Fig 21 shows a cross-section along the line A-A  
12          of Fig 20;  
13          Fig 22 shows an enlarged view of circle B of  
14          Fig 21;  
15          Fig 23 shows an end view of a cup-type seal of  
16          Fig 19;  
17          Fig 24 shows a cross-section along the line A-A  
18          of Fig 23;  
19          Fig 25 shows an end view of a shaft of the cup-  
20          type seal assembly of Fig 19;  
21          Fig 26 shows a cross-section along the line A-A  
22          of Fig 25;  
23          Fig 27 shows an enlarged view of region B of  
24          Fig 26;  
25          Fig 28 shows a side view with interior detail  
26          of a flange of the shaft of Fig 25 and  
27          Fig 29 shows a side view of the anchor of Figs  
28          17 and 18.  
29  
30          As shown in Fig 1, an abandonment string 10  
31          typically comprises a cutting tool 12, a first  
32          circulating sub 14, two oppositely orientated cup-

1 type seal assemblies 16 18, a second circulating sub  
2 20, a third cup-type seal assembly 22 and drill pipe  
3 24.

4

5 An enlarged view of cup-type seal assemblies 16, 18,  
6 22 and circulating subs 14, 20 is shown in Fig 14.

7 Cup-type seal assemblies 16 and 22 provide two  
8 permanent barriers between the hydrocarbon bearing  
9 formation and the surface.

10

11 Optionally, a second cup-type seal assembly and sub  
12 arrangement may be provided beneath the cutting tool  
13 12. This could be useful if the plug 44 in the  
14 innermost casing has not formed a perfect seal. As  
15 shown in Fig 1, the arrangement could comprise a sub  
16 26, fourth and fifth cup-type seal assemblies 28,30  
17 arranged back-to-back, a further sub 32 and a sixth  
18 cup-type seal assembly 34. This cup-type seal  
19 assembly and sub arrangement is inverted as compared  
20 with the arrangement above the cutting tool 12,  
21 except that the subs 26 and 32 can be ordinary subs  
22 instead of circulating subs. It is not necessary to  
23 have this entire arrangement; cup-type seal assembly  
24 28 would be sufficient, or cup-type seal assemblies  
25 28 and 34, if a double seal is required.

26

27 The cutting tool 12 is best shown in Figs 15 and 16.  
28 It has a rotatable jet cut nozzle 70, which can cut  
29 through casing 36. Cutting nozzle 70 is rotatable  
30 in both horizontal and vertical planes to allow the  
31 cutting of communication ports (i.e. cutting nozzle  
32 can cut in two dimensions). Cutting tool 12 has a

1 pair of anchoring devices 74 that are axially spaced  
2 along the body of the tool, to anchor the tool 12 in  
3 the casing 36. Each anchoring device 74 has three  
4 feet 78 that are circumferentially spaced around the  
5 body of the tool 12 and each foot is attached to the  
6 body of the tool 12 by a pair of link arms 72 that  
7 are each pivotally coupled at one end to an eye on  
8 the foot and at the other end to a respective eye on  
9 the body. One of the eyes on the body is mounted on  
10 a central plate that is driven axially by a  
11 hydraulic ram to push the eyes on the body together  
12 thereby extending the feet by means of the pivotal  
13 connections so that the feet move laterally to  
14 contact the casing 36. Fig 16 shows one embodiment  
15 of a part of cutting tool 12, which has a foot 78,  
16 mounted on a pair of link arms 72. The foot 78  
17 typically has an abrasive outer surface with e.g.  
18 serrations so that there is high friction between  
19 the foot 78 and casing 36 when the two are in  
20 contact. Fig 16 also depicts an optional second  
21 foot 80, which is mounted on an extension 82 of the  
22 body of the cutting tool 12. The cutting tool  
23 should have at least one extendable foot 78, and  
24 optionally at least one other foot 78 or 80, or  
25 other high friction casing contacting surface.  
26 Typically there are two or three feet 78 each  
27 circumferentially mounted on pairs of linking arms  
28 72 which are circumferentially spaced around the  
29 tool 12. As shown in Fig 15, more than one plate 74  
30 may be provided.

1 The drill pipe 24 extends to the surface.  
2 Umbilicals also extend from the surface to the  
3 cutting tool 10.  
4

5 The abandonment string 10 is shown inside a  
6 wellbore, which has several layers of casing: 9  
7 5/8", 13 3/8", 20" and 30", which are respectively  
8 designated by numbers 36, 38, 40 and 42.  
9

10 Figs 17 and 18 show a second embodiment of  
11 abandonment string 100 and like parts are designated  
12 by like numbers. Abandonment string 100 differs  
13 from abandonment string 10 in that cup-type seal  
14 assemblies 16 and 18 are shown separated by subs,  
15 whereas in Fig 10, these are shown back to back.  
16

17 Like the Fig 1 embodiment, abandonment string 100 is  
18 run on drillpipe 24. Starting from the top of the  
19 string, the first component is an optional safety  
20 joint 102. This provides a means of disconnecting  
21 drillpipe 24 from abandonment string 100 should the  
22 need arise.  
23

24 A flex pipe 104 runs along the side of drillstring  
25 24 and the rest of abandonment string 100. Flex  
26 pipe 104 typically comprises a 3/4 inch 15K fluid  
27 power hose to supply fluid (slurry) to cutting tool  
28 12. Also running along the side of drillstring 24  
29 parallel to flex pipe 104 are electrical and  
30 hydraulic umbilical lines (not shown) to power and  
31 control the cutting tool 12.  
32

1 The next component in the string is cup-type seal  
2 assembly 22 and associated flex pipe assembly 200.  
3 Cup-type seal assembly 22 is shown in more detail in  
4 Figs 19 to 28. Cup-type seal assemblies 16, 18  
5 further down the string are typically exactly the  
6 same, but for ease of reference numbering, the cup-  
7 type seal assembly is denoted simply as 22.

8  
9 Cup-type seal assembly 22 includes a body member  
10 106, a seal 108, a shaft assembly 110 and an o-ring  
11 seal 112. Body member 106 is substantially  
12 cylindrical. It has a shaft-engaging portion 120  
13 and a seal-engaging portion 122. Shaft-engaging  
14 portion 120 has a smooth outer surface of constant  
15 diameter. Shaft-engaging portion 120 is divided  
16 into two portions with different inner diameters; an  
17 end portion 150 of diameter 188mm and a mid portion  
18 152 of diameter 175mm; end portion 150 and mid  
19 portion 152 are divided by a step 125, which lies at  
20 53mm from the end of body member 106. It should be  
21 noted that throughout this specification all  
22 dimensions are exemplary rather than limiting

23  
24 The outer end of the end portion 150 is provided  
25 with four holes 123 equally spaced around the  
26 circumference for the insertion of grub screws.  
27 Adjacent to holes 123, end portion 150 has 7.375-6  
28 ACME-2G threads 127 which terminate a short distance  
29 before step 125.

30  
31 Mid portion 152 is provided with a groove 124 to  
32 accommodate o-ring seal 112. Mid portion 152 then

1 continues uniformly up to a distance of 92mm from  
2 the end of the shaft-engaging portion 120, where  
3 there is a further step 128 which marks the boundary  
4 between the shaft-engaging portion 120 and the seal-  
5 engaging portion 122.

6  
7 The seal-engaging portion 122 comprises an extension  
8 of the shaft-engaging portion and is provided with  
9 undulations on both of its inner and outer surfaces.  
10 The seal-engaging portion 122 is thinner than the  
11 shaft-engaging portion 120, having a larger inner  
12 diameter and the same outer diameter. Eight radial  
13 apertures 126 are provided in the seal-engaging  
14 portion 122, equally spaced around the  
15 circumference; more or fewer apertures could be  
16 provided here, or even none at all.

17  
18 Seal 108 is best shown in Figs 24 and 25. Seal 108  
19 is also basically cylindrical with a body-engaging  
20 portion 132 and a radially-extending end 130. Body-  
21 engaging portion 132 is shaped to co-operate with  
22 the seal-engaging portion 122 of body member 106.  
23 Body-engaging end 132 of seal 108 is provided with a  
24 cylindrical recess 134 corresponding to the seal-  
25 engaging end 122 of body member 106, i.e. the  
26 cylindrical recess 134 has undulating inner and  
27 outer surfaces adapted to co-operate with the  
28 undulations on seal-engaging end 122. Seal 108 is  
29 coupled to body member 106 by the seal-engaging end  
30 122 of body member 106 engaging the co-operating  
31 cylindrical recess 134 of seal 108, with end 133 of

1 seal 108 abutting against step 128 of body member  
2 106; the undulations act to resist separation.

3  
4 Radially-extending end 130 is an extension of a  
5 body-engaging end 132 and it tapers outwards from  
6 body-engaging end 132, with both the inner and outer  
7 diameters increasing. The inner diameter increases  
8 at a greater rate than the outer diameter, so that  
9 the radially-extending end 130 gets thinner as it  
10 tapers outwards.

11  
12 Seal 108 is preferable made of a rubber composition,  
13 preferably 70-80 durometer Nitrile which is suitable  
14 for hydrocarbon use; however other materials could  
15 also be used.

16  
17 Shaft assembly 110, as best shown in Figs 25 to 28  
18 includes a hollow shaft 140 and flange 142 extending  
19 outwardly of shaft 140. The shaft 140 has a box and  
20 a pin connection on respective opposite ends.

21 Flange 142 is shaped to engage and co-operate with  
22 the shaft-engaging end 120 of body member 106.

23 Flange 142 is provided with 7.375.6 ACME-2G screw  
24 threads 143 on its outer surface for connection with  
25 screw threads 127 on body member 106. Flange 142  
26 has a radial projection 144 on the end of flange 142  
27 closest to the pin connection, and a stepped recess  
28 147 on the opposite end of flange 142. Between  
29 radial projection 144 and threads 143 is an  
30 unthreaded gap 145.

31

1 Flange 142 is provided with eight passages 146 of  
2 11.8mm diameter extending through flange 142  
3 parallel to the axis of shaft assembly 110.  
4 Passages 146 are threaded at their upper and lower  
5 ends for the first 20mm for engagement with  
6 respective bulkhead connections (not shown). One  
7 bulkhead connection is supplied for each end of each  
8 passage 146. Passages 146 are to enable the  
9 electrical and hydraulic umbilical lines to continue  
10 past cup-type seal assembly 22; each umbilical line  
11 terminates at the first bulkhead connection, the  
12 first bulkhead connection provides a continuation of  
13 the umbilical line through respective passage 146 to  
14 the second bulkhead connection on the opposite side  
15 of flange 142, which is in turn connected to a  
16 further umbilical line on the other side of flange  
17 142. The bulkhead connectors can each be sealed  
18 closed, so that if any passage 146 is not being  
19 used, the respective bulkhead connectors are sealed  
20 so that no fluids can get through that passage 146.  
21  
22 Two further passages 141, 148 of larger (25.4mm)  
23 diameter are provided in flange 142. Passages 141,  
24 148 are threaded for the first 5/8 inches at their  
25 upper and lower ends.  
26  
27 Passage 141 allows the flex pipe 104 to continue  
28 through flange 142. Passage 141 also has a bulkhead  
29 connection, in the form of flex pipe assembly 200.  
30 Flex pipe assembly 200 is a means of connecting a  
31 portion of flex pipe 104 on one side of cup-type  
32 seal assembly 22 to a further portion of flex pipe

1 104 on the other side. Flex pipe assembly 200  
2 typically includes a further portion of flex pipe  
3 104 which passes through passage 141 in flange 142;  
4 flex pipe assembly 200 typically includes one or  
5 more seals (not shown) to seal between the exterior  
6 of flex pipe 104 and the interior of passage 141.

7  
8 Two blind passages 149 are also provided in the  
9 flange, equally spaced on either side of passage  
10 141. Blind passages 149 are typically used to  
11 receive bolts to secure flex pipe assembly 200 to  
12 shaft assembly 110.

13  
14 Remaining passage 141 also has a bulkhead connection  
15 on each side of flange 142. Passage 141 can be used  
16 to accommodate a return fluid line or an extra flex  
17 pipe for slurry (not shown) or alternatively, if not  
18 used, it could be sealed closed at its bulkhead  
19 connections.

20  
21 Passages 141, 146, 148, 149 are circumferentially  
22 distributed on flange 142.

23  
24 Referring back to Fig 18, cup-type seal assembly 22  
25 is orientated in the string 100 with the seal end  
26 (and the box connection of shaft assembly 110)  
27 pointing downwards. The pin of shaft assembly 110  
28 is attached to drillstring 24 as shown in Fig 17.

29  
30 When fluid flows into the seal end of cup-type seal  
31 assembly 22 (i.e. fluid flowing upwards on the  
32 outside of string 100 in this embodiment) the

1 radially-extending end 130 of seal 108 is pushed  
2 outwards to engage the casing wall. The greater the  
3 pressure from the fluid, the more the radially-  
4 extending end 130 is pushed against the casing, and  
5 the better the seal. Therefore, fluid flowing  
6 upwards in the annulus between the string 100 and  
7 the innermost casing string cannot get past seal 22.

8  
9 The box of shaft assembly 110 is attached to a pin-  
10 pin sub 202, followed by a crossover sub 204, two  
11 pin-box ported subs 20a, 20b, a further cross-over  
12 sub 210 and a pin-box sub 212. (Note that in this  
13 embodiment, there are two pin-box ported subs 20,  
14 whereas in the Fig 1 embodiment only one was shown).

15  
16 At this point in the string is cup-type seal  
17 assembly 18; this is exactly the same as cup-type  
18 seal assembly 22 and the above description of cup-  
19 type seal assembly 22 is equally applicable here.  
20 However, the orientation of cup-type seal assembly  
21 18 is the reverse of the former seal assembly 22;  
22 i.e. where cup-type seal assembly 22 has its seal  
23 108 pointing downwards, cup-type seal assembly 18  
24 has its seal pointing upwards. Thus, in this case,  
25 it is the box connection of shaft assembly 110 that  
26 is attached to pin-box sub 212. Because of the  
27 opposite orientation, fluid flowing downwards in the  
28 annulus between string 100 and the innermost casing,  
29 is stopped by cup-type seal assembly 18.

30  
31 Also as described above, a further flex pipe  
32 assembly 200 allows flex pipe 104 to pass through

1 passage 141 in flange 142 whilst forming a seal  
2 around the outside of the passage.

3

4 The pin connection of shaft assembly 110 is attached  
5 to pin-box sub 214 and the drillstring continues  
6 with box-box sub 216 and further pin-box sub 218.

7

8 A further cup-type seal assembly 16 and respective  
9 flex pipe assembly 200 is attached to pin-box sub  
10 218. Cup-type seal assembly 16 is exactly the same  
11 as cup-type seal assemblies 18, 22 described above,  
12 and has the same orientation in the string as cup-  
13 type seal assembly 22 (i.e. opposite to assembly  
14 18). Thus, cup-type seal assemblies 16, 22 both act  
15 to prevent fluid flowing upwards from the well to  
16 the surface.

17

18 Connected to shaft assembly 110 of cup-type seal  
19 assembly 16 is a pin-pin sub 220 and pin-box ported  
20 sub 14. Pin-box ported sub 14 has a blind ending,  
21 and three transverse passages (although only one is  
22 necessary) leading from an inner bore to the outside  
23 of abandonment string 100, providing fluid  
24 communication with the outside of the string 100.  
25 Ported sub 14 allows for pressure testing beneath  
26 cup-type seal assembly 16, circulating through  
27 perforations as required and pressure monitoring  
28 during perforations. It also allows a fluid return  
29 path (via the drillpipe 24) for the cutting tool  
30 power fluid whilst cutting operations are in  
31 progress. Furthermore, bullheading the perforated  
32 casing annuli can be carried out via sub 14. Shield

1 bracket 226 is provided on sub 14. The next element  
2 is apertured sub 224, which has at least one side  
3 aperture to allow the entry of flex pipe 104 into a  
4 hollow bore of apertured sub 224. Apertured sub 224  
5 may also have a further aperture for entry of a  
6 further fluid return pipe (not shown) into the  
7 hollow bore.

8  
9 Attached to apertured sub 224 is anchor sub 228;  
10 this is best shown in Fig 29. Anchor sub 228  
11 replaces the anchoring device 74 shown in Figs 15  
12 and 16 (used in abandonment string 10). Anchor sub  
13 228 is a modification of a casing packer.

14  
15 The modification typically includes the removal of  
16 the inner packing material, leaving a central hollow  
17 bore for the passage of flex pipe 104 and the  
18 umbilicals. Anchor sub 228 has a first portion 232  
19 and second portion 234 which are slideable relative  
20 to each other; the second portion 234 having a  
21 tapered portion 238, which in turn has a reduced-  
22 diameter extension 236. The first portion 232 has  
23 grippers 240 on the end closest to the second  
24 portion. To activate anchor 228, the second portion  
25 234 is moved upwards relative to first portion 232,  
26 which causes grippers 240 to be pushed radially  
27 outwards as they travel along tapered portion 238.  
28 Grippers 240 engage the inner surface of the cased  
29 wellbore to anchor abandonment string 100 to the  
30 casing.

31

1 Attached to anchor sub 228 is cutting tool 12, which  
2 can be the same anchoring tool as shown in Fig 15.  
3 Cutting tool 12 in this embodiment does not need to  
4 have feet 78 as abandonment string 100 already has  
5 an anchor 228, although these may be still be  
6 provided if desired.

7  
8 Cutting tool 12 has a hollow internal passage to  
9 allow passage of flex pipe 104 and the umbilical  
10 lines (not shown). Cutting tool 12 has a cutting  
11 nozzle 70 (see Fig 15). The cutting tool 230 is  
12 controlled and powered by the umbilicals; fluid  
13 (typically slurry) is supplied to cutting nozzle 70  
14 by flex hose 104. The remaining features of cutting  
15 tool 12 have already been described above with  
16 reference to Fig 15 and the abandonment string 10  
17 embodiment.

18  
19 In use, when the corrosion cap/temporary abandonment  
20 cap has been removed from the well, a drill string  
21 with a rock bit is run into the wellbore, to check  
22 that it is free of obstructions. The drill string  
23 is typically made up of 3½" or 5" drill pipe.

24  
25 The abandonment string 10, 100 is made up and run  
26 into the hole to a depth of typically 100-400 metres  
27 (in some cases up to several thousand metres)  
28 beneath the wellhead. The top drive is then made up  
29 or the string is connected to a circulation device.

30  
31 With abandonment string 10, the cutting tool 12 in  
32 the string is then anchored to e.g. the 9 5/8"

1 optionally below the wellhead by extending the rams  
2 72 so that the feet 78 contact the casing 36. The  
3 abandonment string 10 is thus held fixed relative to  
4 the casing 36 by friction between the feet 78 and  
5 the casing 36. If abandonment string 100 is used,  
6 anchor 228 is engaged as described above by moving  
7 second portion 234 towards first portion 232 until  
8 the grippers 240 grip the casing sufficiently.

9  
10 As shown in Fig 7, the casing 36 is pressure tested,  
11 to check its integrity. This is done by pumping  
12 fluid down through the abandonment string 10, 100  
13 and out through an aperture in circulating sub 14.  
14 The fluid is constrained within the area bounded by  
15 an existing plug 44 (fitted when the wellbore was  
16 temporarily abandoned), the cup-type seal assemblies  
17 16, 22 and the casing 36. This tests the pressure  
18 integrity of the casing and of the plug 44 and  
19 identifies whether there are any fissures through  
20 which significant amounts of hydrocarbons can leak  
21 from the formation.

22  
23 It may be advantageous to only engage the anchor  
24 after the pressure has already begun to build up.  
25 The anchor is useful to prevent the pressure build  
26 up underneath cup-type seal assembly 16 from forcing  
27 abandonment string 100 out of the well.

28  
29 Assuming that the casing 36 and the plug 44 do not  
30 have any substantial leaks, the cutting tool 12 then  
31 cuts two (typically circular) holes 46, 48 in  
32 opposite sides of the casing 36, as shown in Figs 2

1 and 8. It is not necessary to cut two holes; one  
2 would suffice, nor is it necessary for the holes to  
3 be opposite each other.

4  
5 A second pressure test is then performed by pumping  
6 fluid 50 (e.g. water) through the abandonment string  
7 and out through the aperture in circulating sub 14,  
8 in the same manner as the first pressure test. The  
9 fluid 50 passes out through the holes 46 and 48 and  
10 into the annulus 52 between the casing 36 and the  
11 casing 38. Some of the fluid 50 may escape down the  
12 annulus 52 and into the formation. The rate of  
13 pumping is varied so that equilibrium is reached  
14 between the amount of fluid 50 entering and leaving  
15 the annulus 52. The equilibrium rate of pumping and  
16 pressure are recorded. A typical equilibrium rate  
17 might be 2-3 barrels per minute at a pressure of  
18 3,000 pounds per square inch. This test is done to  
19 establish a bench mark for the next pressure test.  
20 It also establishes the integrity of the casing 38;  
21 if there is very low pressure in the annulus 52  
22 after pumping fluid 50 into it, that could indicate  
23 leaks in the casing 38 or the cement job. If there  
24 is a very high back pressure, which could be caused  
25 by hydrocarbons in the annulus/formation, the excess  
26 fluid will have to be removed via the string before  
27 proceeding.

28

29 The anchoring means are then deactivated to release  
30 the cutting tool 12 from the casing 36 and the  
31 abandonment string 10, 100 is then raised so that  
32 the cutting tool 12 is approximately 400-500 feet

1     above the first cuts 46,48 as shown for example in  
2     Figs 3 and 9. The anchoring means are then  
3     reactivated so that the cutting tool 12 is re-  
4     anchored to the casing 36 (i.e. by extending the  
5     link arm 72 to push the feet 78, 80 against the  
6     casing 36 in the Fig 1 embodiment, or by moving the  
7     first and second portions 232, 234 away from each  
8     other in the Fig 17 embodiment). A pair of second  
9     cuts 54, 56 are made with the cutting tool 12 in  
10    opposite sides of the casing 36 as before. Again,  
11    it is not necessary to cut twice; one cut would  
12    suffice. In some cases a further pressure test as  
13    described previously can be carried out through the  
14    newly made cuts 54, 56, but this is not necessary.

15  
16    The anchoring device is then deactivated to release  
17    the cutting tool 12 from the casing and the  
18    abandonment string 10 is lowered down the borehole  
19    so that the cup-type seal assemblies 16 and 22 are  
20    between the two sets of cuts 46, 48 and 54, 56, as  
21    shown in Fig 10. Fluid is then pumped from the  
22    lower sub through cuts 46, 48 and into the annulus  
23    52 between the two sets of cuts 46, 48 and 54, 56.  
24    If the fluid pathway is open in the annulus 52,  
25    fluid pumped through the string 10 should flow  
26    through cuts 54, 56 without significant measurable  
27    pressure build up at surface.

28  
29    The abandonment string 10 is then detached from the  
30    casing, lowered and re-anchored so that the first  
31    cuts 46, 48 are positioned between cup-type seal  
32    assemblies 18 and 22, as shown in Fig 11. A ball or

1     dart is dropped through the abandonment string 10 so  
2     that it diverts fluid from the circulating sub 14.  
3     Cement is then pumped down the abandonment string  
4     10. The cement 58 passes out of the hole 20 in  
5     circulating sub and into the annulus 52.

6  
7     When no more cement can be pumped in at a reasonable  
8     rate and pressure (with reference to the readings  
9     taken earlier) this indicates that the annulus  
10    between the cuts is well sealed. Alternatively a  
11    cement slug of a known volume can be injected into  
12    the string and is pumped through the tool 12. The  
13    volume of the slug is calculated to create a plug  
14    extending the length of the annulus between the cuts  
15    46, 48 and the cuts 56, 58. Typically the distance  
16    between the first and second cuts is at least 100  
17    feet, and typically an excess of cement (e.g. 2-  
18    300%) is used in order to ensure that the annular  
19    cement plug is sufficiently long.

20  
21    The anchoring devices are then deactivated and the  
22    string 10 is pulled up out of the borehole before  
23    the cement sets. Excess cement that has emerged  
24    from the upper cuts 56, 58 is wiped out of the bore  
25    by the seals on the tool 12. At this time, the tool  
26    can be redressed to remove the ball/dart from the  
27    circulating sub 14 so that fluid can circulate  
28    through the sub 14 once more.

29  
30    When the new cement is set, the string 10 is run  
31    into the borehole again so that the cup-type seal  
32    assemblies 16, 22 are in between cuts 46, 48 and

1 cuts 54, 56, as shown in Figs 5 and 12. The annular  
2 plug of cement in the section 60 of annulus 52  
3 between the cuts 46, 48 and cuts 54, 56 should now  
4 be solid. To test this, fluid (e.g. water) is then  
5 pumped down the string 12 and through the hole in  
6 the circulating sub 14. If no significant injection  
7 of fluid into the annulus 52 is possible, then this  
8 proves that the cement job has been successful and  
9 that the section 60 of annulus 52 is firmly sealed.

10

11 If this is the case, the tool 10 is unanchored,  
12 raised and re-anchored so that the cutter of the  
13 cutting tool 12 is near the wellhead. The cutting  
14 tool 12 is then used to cut through all the casings  
15 36, 38, 40, 42 by continuous cutting while the head  
16 rotates around 360°.

17

18 In the case of the string 100, the procedure is the  
19 same but the port 20a between the cups 22,18 can  
20 optionally be used for cement injection, whereas the  
21 other port 20b can be used for pressure testing  
22 between the upper 22 and lower 18 seals prior to any  
23 perforations being made. Thus testing of the upper  
24 and the lower seals 22, 16 can optionally be done  
25 without moving the string.

26

27 Modifications and improvements may be incorporated  
28 without departing from the scope of the invention.  
29 For example, after the cement has been injected into  
30 the annulus, instead of withdrawing the string  
31 10,100 back to surface, the string 10,100 can be  
32 pulled up just above the upper perforations 54,56,

1 to wait on cement (if a cement slug has been used)  
2 or can be pulled up until the ports 20 are above the  
3 wellhead, where the cement can be purged from the  
4 drillstring, the port 20a, and the area between the  
5 seals 22,18. When the cement has been purged (if  
6 necessary) then the string 10,100 can be run back  
7 into the hole to test the integrity of the annular  
8 cement seal at 60, by pumping seawater through  
9 either of ports 20a and 20b. This therefore allows  
10 the whole operation to be completed in a single run.  
11 In a further modification of the method, further  
12 radially outward annuli can be sealed in exactly the  
13 same way, optionally on the same run in the hole, by  
14 cutting through the two innermost layers of casing  
15 and into the second annulus behind that already  
16 sealed. Typically the plug in the second annulus  
17 overlaps the first plug, in accordance with normal  
18 procedures, and this can be achieved by making the  
19 first cut for the second plug between the first and  
20 second cuts of the first, and then raising the  
21 string 10,100 to a level above the second (upper)  
22 cuts of the first plug, before making the second  
23 (upper) cuts for the second plug. Clearly the outer  
24 plug could be set at a lower level than the first  
25 plug.

26

27 The high pressure rating of the tool allows control  
28 of hydrocarbons behind the perforated casings, and  
29 also can be used to inject behind numerous radially  
30 outward casings outside the innermost casing, or to  
31 break down the formation at these points. This  
32 high-pressure capability is useful if bullheading is

1 required. Cutting through radially outward casing  
2 strings can be detected by observing pressure drops  
3 in the slurry hose.

4  
5 When moving the string 10,100 through the hole the  
6 plunger effect can be minimised by allowing free  
7 passage of fluid through the string 10,100. Also,  
8 swabbing can be minimised when pulling out by  
9 pumping fluid down the string 10,100.

10

11 Embodiments of the present invention have the  
12 advantage that no explosives are used, which makes  
13 it more environmentally friendly. This also  
14 eliminates the risk of shattering the well plugs  
15 using explosives. Also, by following the method  
16 described above, the casing can be perforated and  
17 pressure tested, cement injected into the annulus  
18 between casings to seal the annulus and the casings  
19 severed all on a single run operation. Furthermore,  
20 the cutting tool can also be used to cut the  
21 concrete pancake at the top of the wellhead,  
22 breaking it up and hence reducing the amount of  
23 weight to be lifted after the casings are severed.  
24 The equipment is usually run on a drillstring, and  
25 can be run on coil tubing, so the abandonment string  
26 can be run from a derrick vessel, or a floating/  
27 jack-up rig, without requiring more expensive and  
28 permanent platforms, or even diving support vessels.

29